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G1G GEL GMB

(56) Documents Cited:
US 5996726 A **US 5377104 A**
US 4516206 A

(58) Field of Search:
UK CL (Edition W) **G1G**
INT CL[7] **E21B, G01V**
Other: **WPI, EPODOC, JAPIO, INSPEC**

(54) Abstract Title: **Microseismic determination of location and origin time of a fracture generated by fracturing operation in a hydrocarbon well**

(57) In a method of monitoring a hydraulic fracturing operation in a hydrocarbon well 11, microseismic signals 14 originating from an induced fracture 14 are recorded by three component geophone arrays 121,131 in neighbouring wells 12,13. A wavefield inversion algorithm is used to determine the mechanism, origin time and location of the seismic source 14. The algorithm does not require the signals to be resolved into P-wave and S-wave data before inversion. The algorithm evaluates Green's functions, uses an existing velocity model and decomposes a moment tensor to yield parameters characteristic of the fracture. The recorded signals may be bandpass limited to 0-50 Hz or 0-100 Hz.

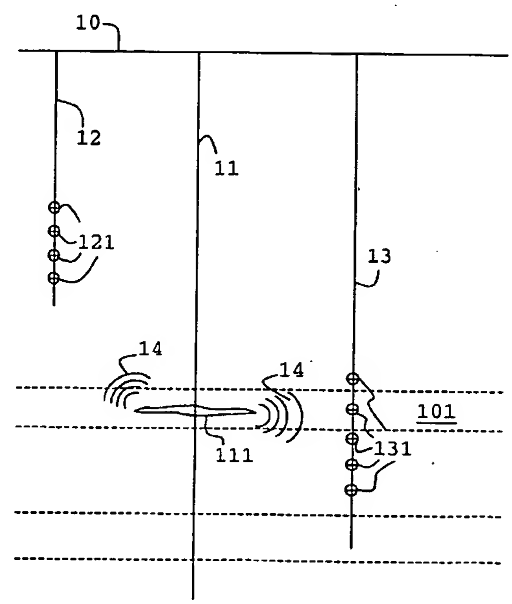

FIG. 1

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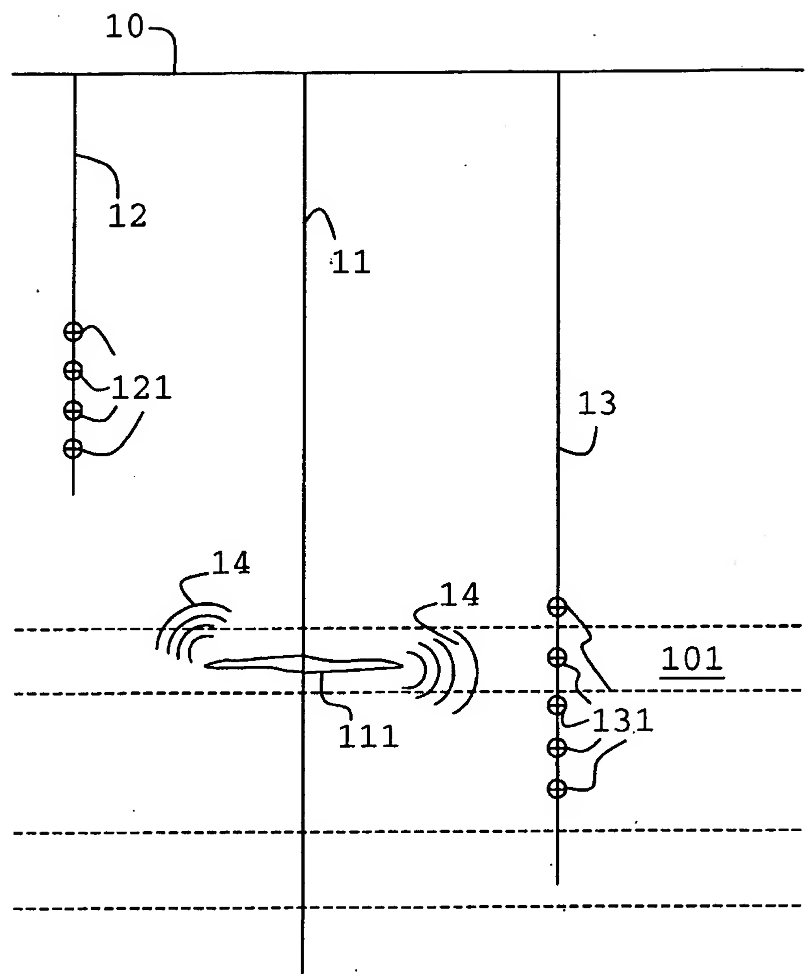

FIG. 1

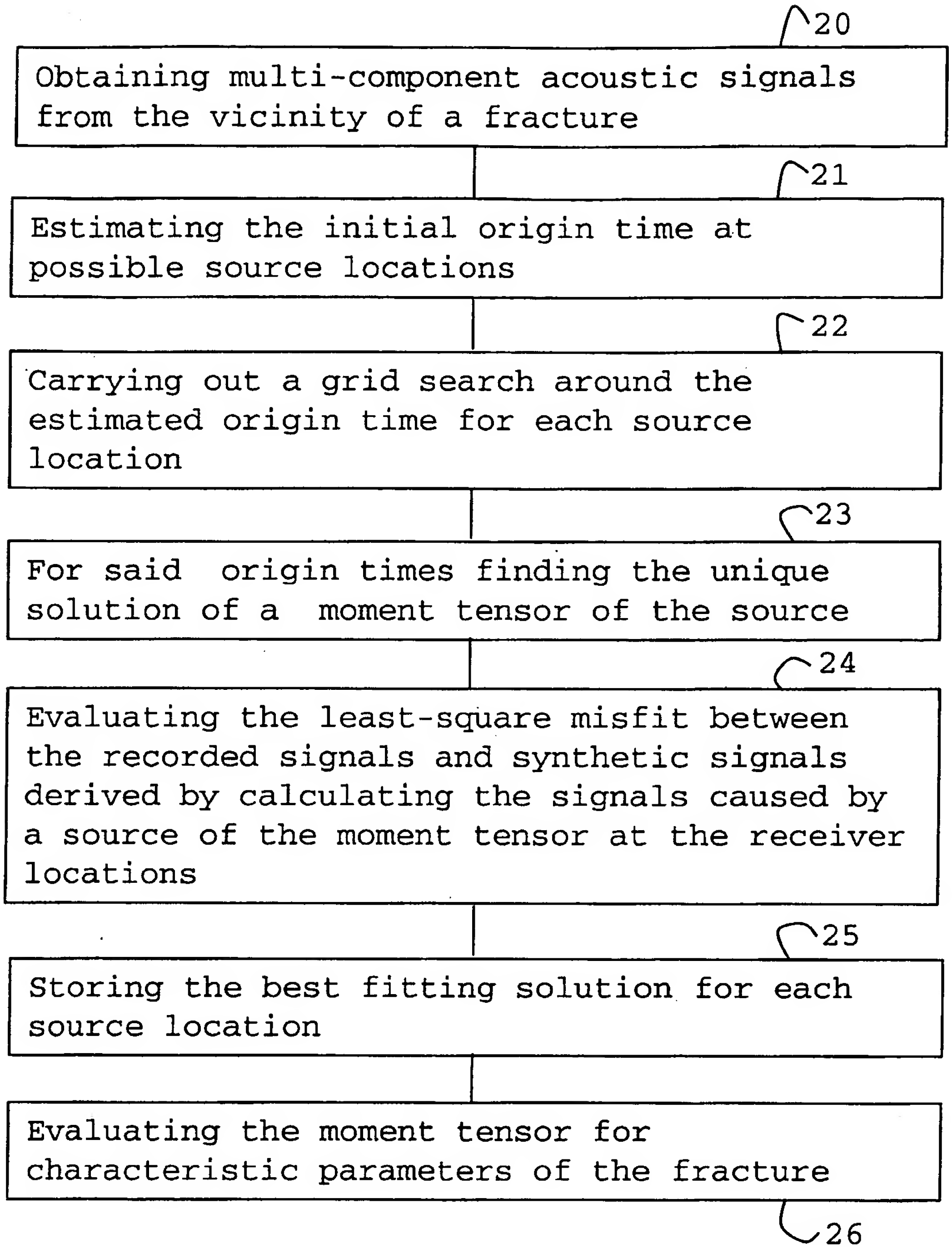
20
Obtaining multi-component acoustic signals from the vicinity of a fracture
21
Estimating the initial origin time at possible source locations
22
Carrying out a grid search around the estimated origin time for each source location
23
For said origin times finding the unique solution of a moment tensor of the source
24
Evaluating the least-square misfit between the recorded signals and synthetic signals derived by calculating the signals caused by a source of the moment tensor at the receiver locations
25
Storing the best fitting solution for each source location
Evaluating the moment tensor for characteristic parameters of the fracture
26

FIG. 2

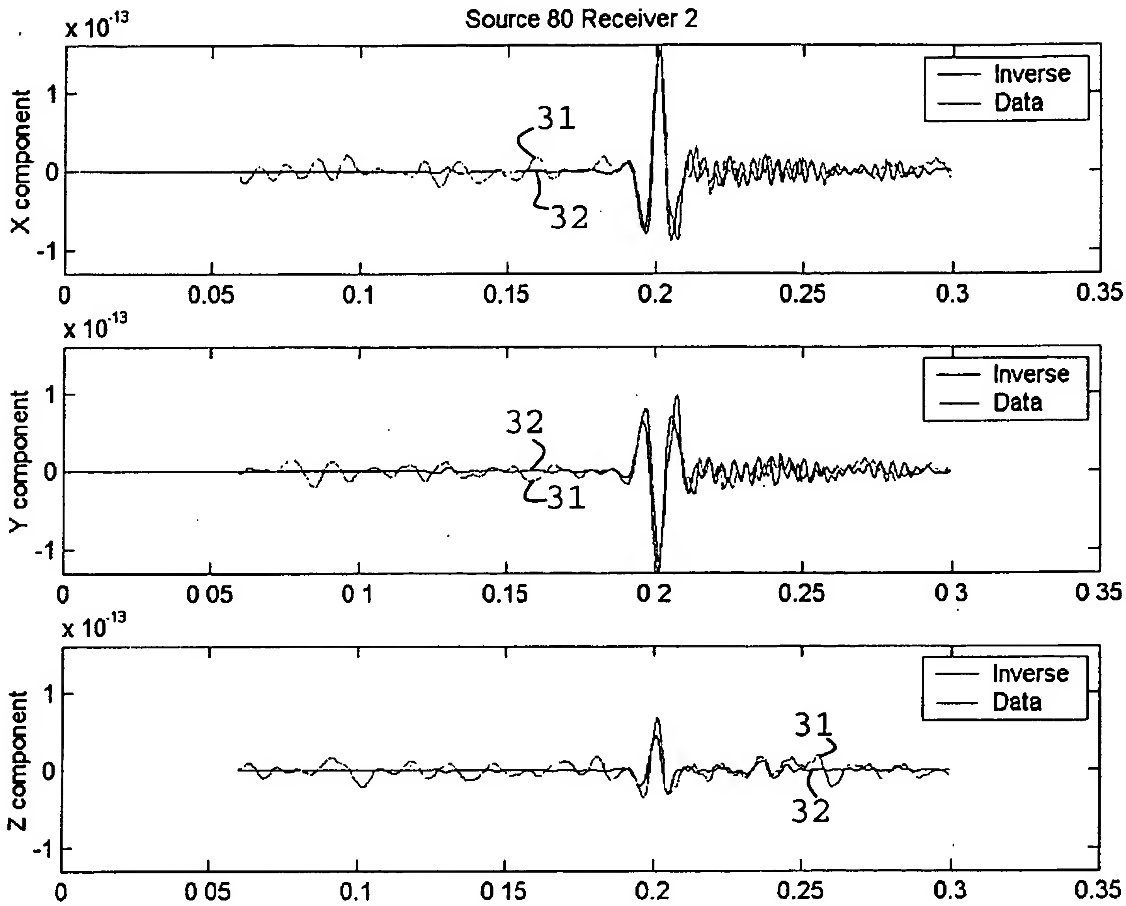
Source 80 Receiver 2
x 10^-13
X component
Inverse
Data
31
32
1
0
-1
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
x 10^-13
Y component
Inverse
Data
32
31
Z component
Inverse
Data
31
32

FIG. 3

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Method for Monitoring Hydraulic Stimulation

This invention relates to methods for acquiring seismic data monitoring hydraulic stimulation such as fracturing rock layers to improve hydrocarbon production of a well. More specifically it relates to such methods using seismic methods to detect the location of an induced fracture.

BACKGROUND OF THE INVENTION

In certain situations, workers in the oil and gas industry perform a procedure known as "hydraulic fracturing" during oil exploration and drilling operations. For example, in formations where oil or gas cannot be easily or economically extracted from the earth, a hydraulic fracturing operation is commonly performed. Such a hydraulic fracturing operation includes pumping in large amounts of fluid to induce cracks in the earth, thereby creating pathways via which the oil and gas may flow. After a crack is generated, sand or some other material is commonly added to the crack, so that when the earth closes back up after the pressure is released, the sand helps to keep the earth parted. The sand then provides a conductive pathway for the oil and gas to flow from the newly formed fracture

However, the hydraulic fracturing process does not always work very well. The reasons for this are relatively unknown. In addition, the hydraulic fractures cannot be readily observed, since they are typically thousands of feet below the surface of the earth. Therefore, members of the oil and gas industry have sought diagnostic methods to tell where the fractures are, how big the fractures are, how far they go and how high they grow. Thus, a diagnostic apparatus and method for measuring the hydraulic fracture and the rock deformation around the fracture are needed.

In previous attempts to solve this problem, certain methods have been developed for mapping fractures. For example, one of these methods involves seismic sensing. In such a seismic sensing operation, micro-earthquakes generated by the fracturing are analyzed by seismic meters, for example, accelerometers.

A recent study on the use of microseismic imaging for fracture stimulation was published by J. T. Rutledge and W. S. Phillips. In an typical operational setting as described in greater detail in FIG. 1 below, three-component geophones were used to monitor a well during fracturing. The recordings of the geophones are then converted into arrival times and source location using an iterative, least square method.

The present invention seeks to improve the amount of information gained from microseismic imaging of fracturing operations.

SUMMARY OF THE INVENTION

The invention describes a waveform inversion algorithm to determine the mechanism, origin time and location of a seismic source. The algorithm is fully automatic, i.e. it does not require detection of seismic phases (such as P or S waves) or other parameters derived from data (e.g. polarization angles). The algorithm is suitable for inversion in an arbitrary heterogeneous medium and takes advantage of a good velocity and density model, if it is available. An alternative version of the inversion algorithm (with location or origin time of the seismic source determined independently) can be used to invert for the mechanism of the source only. The algorithm uses reciprocity of the source and receivers by evaluating Green's functions

in an arbitrary heterogeneous medium from the receiver locations. These Green's functions are then inverted to evaluate synthetic seismograms due to an arbitrary source mechanism from source locations.

Using preferably a grid search over all possible source locations and origin times, the full waveform synthetic seismograms are fitted to the data by the least-square method. The initial estimate of the origin time is set through cross-correlation of data and synthetics due to an arbitrary source mechanism.

The inverted origin time is determined by a grid search around this initial estimate. The algorithm is robust to white noise added to the synthetic seismograms and is robust and particularly suitable for low frequency data in the frequency band from 0 Hz to 100 Hz, more preferably 0 Hz to 50 Hz.

These and further aspects of the invention are described in detail in the following examples and accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

The invention will now be described, by way of example only, with reference to the accompanying drawings, of which:

FIG. 1 shows a schematic illustration of fracturing operation;

FIG. 2 is a flowchart of steps performed in an example of the present invention; and

FIG. 3 is a comparison of synthetic data with data derived using an example of the present invention.

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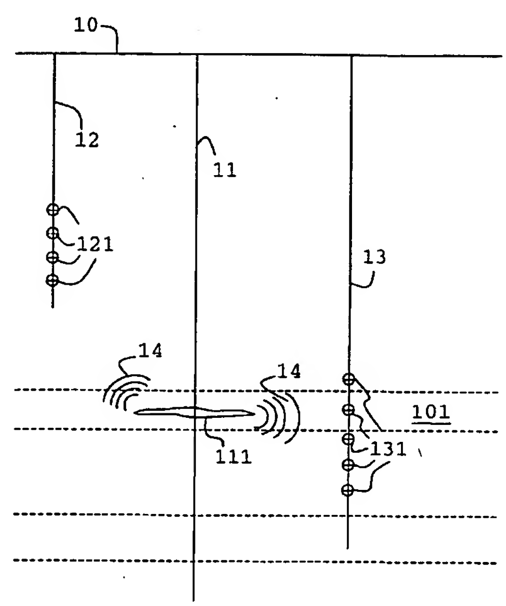

FIG. 1

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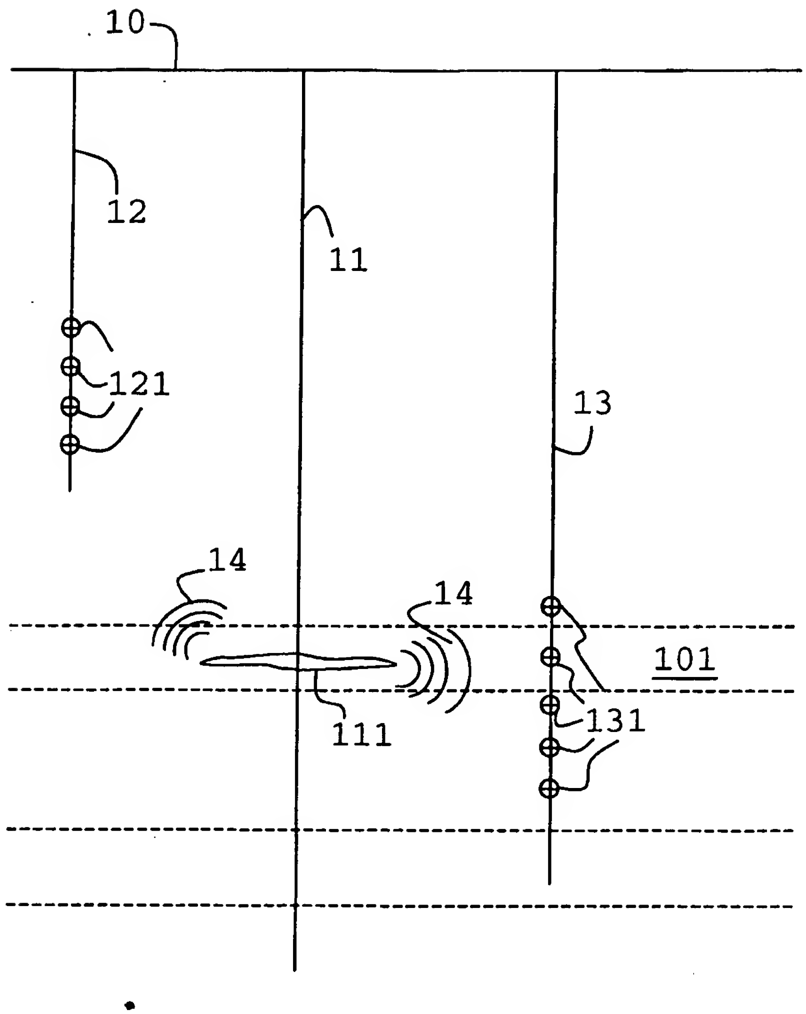
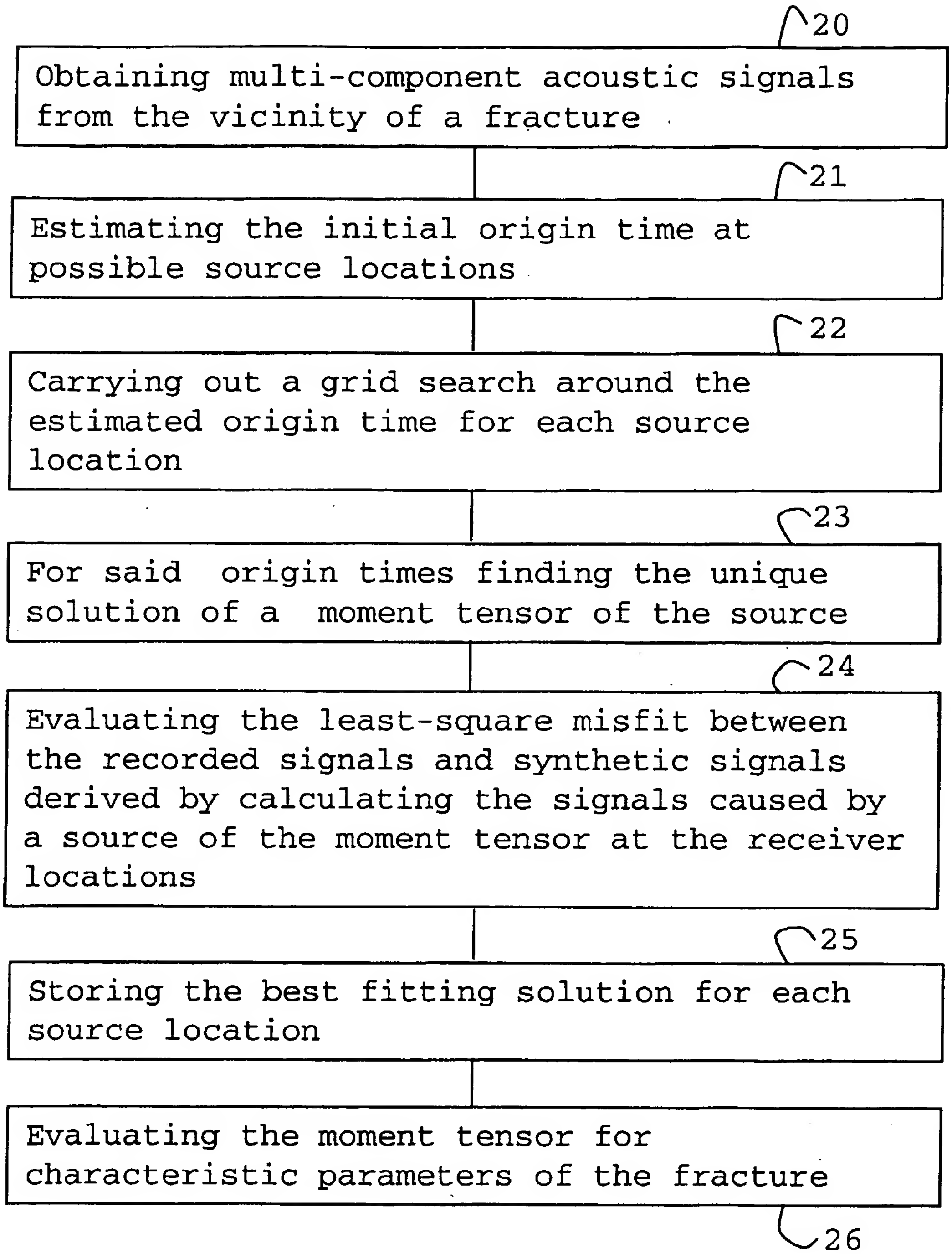


FIG. 1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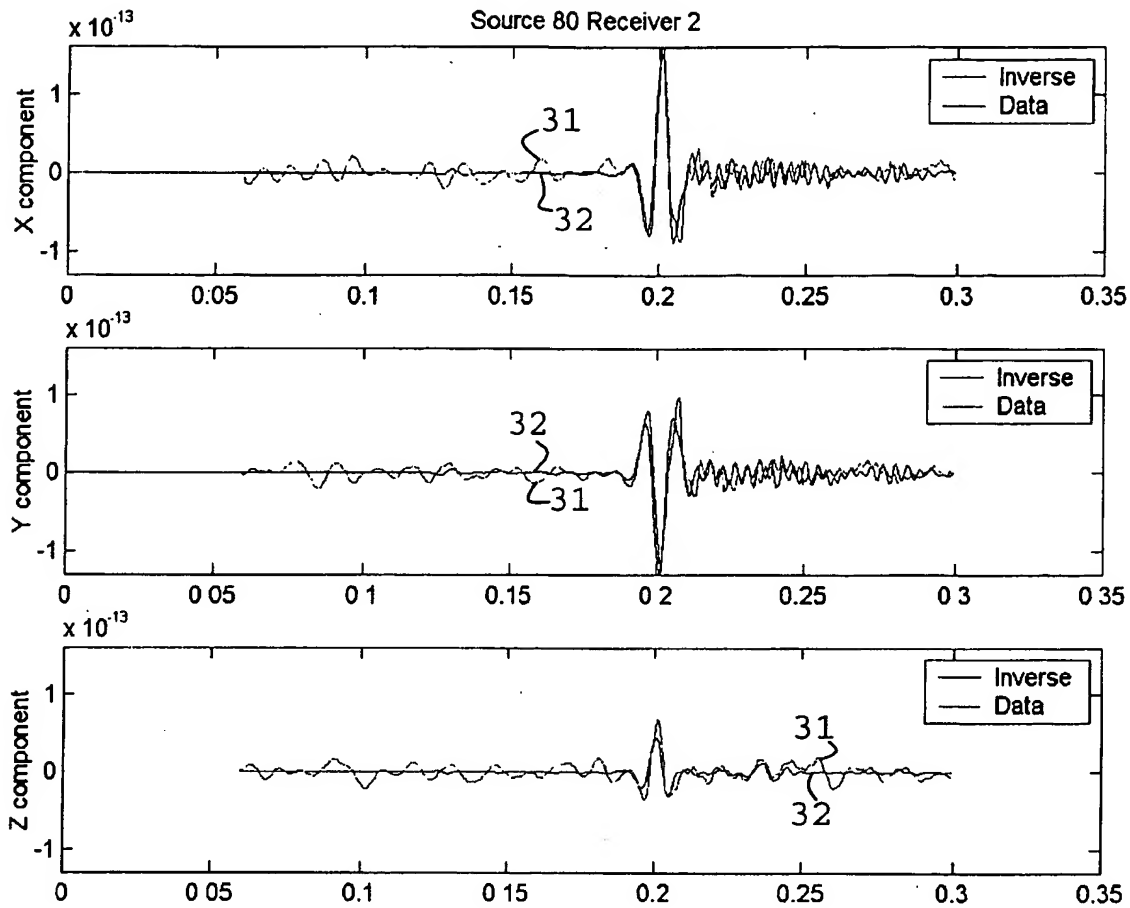
Source 80 Receiver 2
x 10^-13
X component
Inverse
Data
31
32
1
0
-1
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
x 10^-13
Y component
Inverse
Data
32
31
x 10^-13
Z component
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32

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However, the hydraulic fracturing process does not always work very well. The reasons for this are relatively unknown. In addition, the hydraulic fractures cannot be readily observed, since they are typically thousands of feet below the surface of the earth. Therefore, members of the oil and gas industry have sought diagnostic methods to tell where the fractures are, how big the fractures are, how far they go and how high they grow. Thus, a diagnostic apparatus and method for measuring the hydraulic fracture and the rock deformation around the fracture are needed.

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in an arbitrary heterogeneous medium from the receiver locations. These Green's functions are then inverted to evaluate synthetic seismograms due to an arbitrary source mechanism from source locations.

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These and further aspects of the invention are described in detail in the following examples and accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

The invention will now be described, by way of example only, with reference to the accompanying drawings, of which:

FIG. 1 shows a schematic illustration of fracturing operation;

FIG. 2 is a flowchart of steps performed in an example of the present invention; and

FIG. 3 is a comparison of synthetic data with data derived using an example of the present invention.

DETAILED DESCRIPTION

A typical operational setting for monitoring hydraulic fracturing is illustrated in FIG 1 with a treatment well **11** and geophone arrays **121**, **131** located in neighboring wells or holes **12**, **13**. During the fracturing operation a fluid is pumped from the surface **10** into the well **11** causing the surrounding formation in a hydrocarbon bearing layer **101** to fracture. Acoustic waves **14** generated by the fracture **111** propagate through the earth and are recorded by the three-components geophones of the two arrays **121**, **131**.

For the present invention it is assumed that three components of the time history of particle velocity (or particle displacement) at several (N_r) downhole receivers were recorded during an acoustic emission. Furthermore, it is assumed the existence of an velocity model (of arbitrary complexity) of the volume of earth through which the seismic waves travels. The quality of the velocity model can be characterized by the length of time interval T_i ($i= 1..N_r$) for which one is confident a synthetic seismograms can fit the data. These time intervals preferably include at least the S-wave arrival at all of the receivers. The use the particle displacement is preferred as it stabilizes the inversion as the particle velocity is more oscillatory than particle displacement.

To find the relevant source parameters such as location vector x_s, origin time t_0 and moment tensor M, the misfit between a synthetic seismograms and data is minimized. In this inversion the misfit is defined by equation [1]:

[1]

$$\Delta = \sum_{i=0}^{N_r} \sum_{j=0}^{3} \int_0^{T_s} \left(d_j(\mathbf{x}_r^i, t - t_0) - U_j(\mathbf{x}_s, \mathbf{x}_r^i, t, M) \right)^2 dt$$

where d_j denotes a component of the particle velocity recorded at the i-th receiver and U_j is the j-th component of the synthetic seismogram at the i-th receiver due to a source located at x_s characterized by a moment tensor M. To facilitate the description characters following a underscore appear as subscript in the equations.

The source parameters that minimize equation [1] comprise the inverted solution. The j-th component of a synthetic seismogram at i-th receiver x^{i}_r due to sources at locations x_s can be evaluated from the well known relation

[2]

$$U_j(\mathbf{x}_s, \mathbf{x}_r^i, t, M) = \sum_{\mathbf{x}_s} G_{kj,m}(\mathbf{x}_s, \mathbf{x}_r^i, t) * M_{km}(\mathbf{x}_s, t).$$

Here "*" is a convolution in time, G_kj,m is the derivative of the Green's function along m-th coordinate axis and M_jk is a moment tensor of a point source located at x_s.

The least-square minimum of the misfit given by equation [1] is in general non-unique. To alleviate this problem, it is preferred to make two assumptions: Firstly, approximating the source as a single point source x_s so that the sum over x_s in equation [2] disappears. Secondly, the source-time function can be approximated as a delta source-time function so that the convolution in the equation [2] is replaced by a

multiplication. Using these approximations the equation [2] reduces to

[3]

$$\begin{aligned}
U_j(\mathbf{x}_s, \mathbf{x}_r^i, t, M) &= G_{ij,k}(\mathbf{x}_s, \mathbf{x}_r^i, t) \cdot M_{jk}(\mathbf{x}_s) \\
&= G_{1j,1}(\mathbf{x}_s, \mathbf{x}_r^i, t) \cdot M_{11}(\mathbf{x}_s) \\
&+ G_{2j,2}(\mathbf{x}_s, \mathbf{x}_r^i, t) \cdot M_{22}(\mathbf{x}_s) \\
&+ G_{3j,3}(\mathbf{x}_s, \mathbf{x}_r^i, t) \cdot M_{33}(\mathbf{x}_s) \\
&+ \left(G_{2j,1}(\mathbf{x}_s, \mathbf{x}_r^i, t) + G_{1j,2}(\mathbf{x}_s, \mathbf{x}_r^i, t)\right) \cdot M_{21}(\mathbf{x}_s) \\
&+ \left(G_{3j,1}(\mathbf{x}_s, \mathbf{x}_r^i, t) + G_{3j,1}(\mathbf{x}_s, \mathbf{x}_r^i, t)\right) \cdot M_{31}(\mathbf{x}_s) \\
&+ \left(G_{3j,2}(\mathbf{x}_s, \mathbf{x}_r^i, t) + G_{3j,2}(\mathbf{x}_s, \mathbf{x}_r^i, t)\right) \cdot M_{32}(\mathbf{x}_s).
\end{aligned}$$

It is known that equation [3] has a unique solution for M with a fixed origin time t_0, point-source location x_s and inversion model. Therefore, the trade-off among the source parameters can be minimized by a grid search over source locations and origin times for the best fitting moment tensors. The grid search for all possible origin times is numerically expensive and is therefore accelerated by estimating the origin time from cross-correlation of the synthetics and data and then using the grid-searching around this initial guess. The method used includes the following steps as illustrated in FIG. 2:

- Following a recording of acoustic data from a fracture (Step **20**);
- estimate the initial origin time t_0(x_s) at every possible source location x_s (Step **21**);
- carry out a grid search around the estimated origin time for each source location (Step **22**). For each origin time find the unique solution M(x_s,t_0(x_s))(least-square minimum) (Step **23**)and evaluate the least-square misfit between the data and the synthetics (Step **24**); and
- store the best fitting solution for each source location (Step **25**).

The moment tensor of fracture together with the origin time and location can then be further evaluated (Step **26**) as described below to find characteristics of the fracture.

The initial estimate of the origin time is evaluated by cross-correlation of the data and synthetic seismograms for an chosen source mechanism, e.g. vertical strike-slip. The cross-correlation is evaluated over the time interval $(0, T_j) for each receiver j. The absolute values of the corresponding components for each receiver are cross-correlated and the time shifts of the maximum cross-correlation for each component are calculated. Using the absolute values of the seismograms for the cross-correlation reduces the dependency on the unknown source mechanism. The time shifts of each component and the known origin times of synthetic seismograms enables an estimation of the absolute origin time t^0_ij for each component i and receiver j. The estimates are weighted by the maximum amplitude of the recorded seismograms to reduce poor estimates resulting from cross-correlating traces dominated by noise. It is worth noting that using the maximum amplitude as a weight in averaging the origin time assumes that the signal-to-noise ratio is proportional to the maximum amplitude of the recorded seismograms. The final estimate of the origin time is therefore an arithmetic weighted-average with weights of maximum amplitudes A_ij of i-th component at j-th receiver:

[4]

$$t_0(\mathbf{x}_s) = \frac{\sum_{j=0}^{N_r} \sum_{i=0}^{3} t_{ij}^o A_{ij}}{\sum_{j=0}^{N_r} \sum_{i=0}^{3} A_{ij}}.$$

This cross-correlation can be further improved at the expense of a more time intensive calculation by using the signal envelopes instead of the amplitudes.

The true origin time is then found by grid-search around the initial estimate of the origin time within the dominant [shortest] period in the signal. The limiting of the grid search to the dominant period of the signal requires the initial estimate of the origin time [4] to be within the dominant period. This is typically the case for the S-wave arrival. The grid search around the initial estimate of the origin time [4] eliminates the problems with the cycle-skipping as the cross-correlation function tends to peak every 1/2-period of the dominant period (usually the minimum period present in the data).

The length of the time step in the grid search is set to obtain the required accuracy of the misfit [1]. Assuming that the synthetic seismograms match the data (i.e. using the true moment mechanism and evaluating the synthetic seismograms in the true model from the true source location), normalized misfit of a harmonic signal with period T, due to a time shift of αT in the origin time, can be evaluated as

[5]

$$E = \frac{\int_0^T [\sin(\omega t) - \sin(\omega(t+\alpha T))]^2 dt}{2\int_0^T [\sin(\omega t)]^2 dt} = 1 - \cos(2\pi\alpha).$$

The definition of error in equation [5] has a maximum of 2 for 1/2 period shift and even a small time shift causes a large error for a misfit defined analogously to equation

[1]. The length of time step for the grid search can be set to 2αT for which the maximum error of evaluation of misfit reaches a certain limit. For example, a shift of 0.05 T$ (α=0.05) may cause relative error E=0.05. Thus, a search for origin time with a grid step of 0.1T (T is the dominant period in my seismograms) should not cause an error of evaluation in the misfit function larger than 0.05.

The last part of the method is to identify a unique solution M(x_s, t_0(x_s)) for each origin time and source location. It is known that the moment tensor with the least-square minimum fit of the equation [1] is:

[6]

$$\bar{M}_i(\mathbf{x}_s) = (A^{-1})_{ij}(\mathbf{x}_s) D_j(\mathbf{x}_s).$$

Here M_I(bar) is the i-th component of six elements vector: M_I(bar) = M_11, M_2(bar) = M_12= M_21, M_3(bar) = M_22, M_4(bar) = M_13 = M_31, M_5(bar) = M_3 = M_32, M_6(bar) = M_33, and D has six independent elements

[7]

$$D_k(\mathbf{x}_s) = \sum_{i=0}^{N_r} \sum_{j=0}^{3} \int_0^{T_i} g_{jk}(\mathbf{x}_s, \mathbf{x}_r^i, t - t_0) d_j(\mathbf{x}_r^i, t) dt.$$

Here k=0...5 and g_jk is defined by the following notation:

[8]

$$
\begin{aligned}
g_{j1}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{1j,1}(\mathbf{x}_s,\mathbf{x}_r,t)\\
g_{j2}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{2j,1}(\mathbf{x}_s,\mathbf{x}_r,t)+G_{1j,2}(\mathbf{x}_s,\mathbf{x}_r,t)\\
g_{j3}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{2j,2}(\mathbf{x}_s,\mathbf{x}_r,t)\\
g_{j4}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{3j,1}(\mathbf{x}_s,\mathbf{x}_r,t)+G_{1j,3}(\mathbf{x}_s,\mathbf{x}_r,t)\\
g_{j5}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{3j,2}(\mathbf{x}_s,\mathbf{x}_r,t)+G_{2j,3}(\mathbf{x}_s,\mathbf{x}_r,t)\\
g_{j6}(\mathbf{x}_s,\mathbf{x}_r,t) &= G_{3j,3}(\mathbf{x}_s,\mathbf{x}_r,t).
\end{aligned}
$$

Finally, A is a 6x6 matrix with elements:

[9]

$$A_{kl}(\mathbf{x}_s)=\sum_{i=0}^{N_r}\sum_{j=0}^{3}\int_0^{T_i} g_{jk}(\mathbf{x}_s,\mathbf{x}_r^i,t)\,g_{jl}(\mathbf{x}_s,\mathbf{x}_r^i,t)\,dt.$$

The integration steps of [7] and [9] can be accelerated by using a time window t_min to t_max, where t_min is a time of arrival of a first energy from the source(fracture) as identified by an event detector and t_max is the maximum time for which the waveforms are matched, e.g., the time of arrival of the phase with maximum amplitude. This modification excludes the effect of reflections or tube waves in the recorded data.

It is further feasible to associated with every recording device or trace a weighting function that indicates the quality of the receiver and/or recorded data. These weights could be introduced into the present equations [7] and [9].

The synthetic Green's function in equation [3] is then evaluated by computing three times N_r full waveform

simulations (using a finite-differences). For each three-component receiver, three responses due to three orthogonal single force sources at the receiver positions are computed and derivatives of the velocity (or displacement) are stored at every possible source location, x_s. The synthetic seismograms are evaluated with a delta function as a source-time function. Using reciprocity, derivatives of Green's functions for every possible source location to every receiver position are evaluated. Equation [3] shows that six traces at every possible source location must be stored.

The above equation provides a complete set of steps to calculated the moment tensor M from three component recordings of the wavefield. The tensor itself is then decomposed to yield parameters characteristic of the fracture. Methods to decompose the moment tensor M have been developed for the purpose of analyzing earthquakes and are described for example by V. Vavrycuk in: Journal of Geophysical Research, Vol 106, No B8, August 10, 2001, 16,339-16,355. The parameters obtained by such decomposition include the normal of the fracture n, the slip direction N, and products of the Lame coefficients with the slip u of the fracture, i.e., μu and λu respectively. Alternatively, the moment tensor can be inverted for a set of parameters including the orientation of the pressure P and tension T axes, parameter $\kappa = \lambda/\mu$ and inclination α of the slip u from the fracture. These parameters provide information on the fracture orientation and slip direction which in turn can be used to control the hydraulic fracturing operation.

The accuracy of the inversion from recorded data d_j to the moment tensor M of the source can be further improved by bandlimiting the frequency of the data. While restricting data to the 0-100 Hz band yields satisfactory results, an

improved accuracy is gained by limiting the data further to the 0-75 Hz and even the 0- 50 Hz band. In FIG. 3 there is shown a plot of (synthetic) geophone velocity measurements **31** in x, y and z directions overlaid with the corresponding traces **32** re-calculated using the moment tensor derived by the method described above (with a known velocity model).

CLAIMS

1. A microseismic method of monitoring fracturing operation in hydrocarbon wells comprising the steps of obtaining multi-component signal recordings from locations in the vicinity of a facture; and performing a wavefield inversion to determine parameters representing a source mechanism of said fracture.

2. The method of claim 1 wherein the signal recordings are at least for the purpose of determining the moment tensor bandlimited to 0 to 100 Hz.

3. The method of claim 1 wherein the signal recordings are at least for the purpose of determining the source mechanism bandlimited to 0 to 50 Hz.

4. The method of claim 1 wherein the signal recordings are at least for the purpose of determining the source mechanism bandlimited to 5 to 50 Hz.

5. The method of claim 1 wherein the signal recordings are not resolved into P-wave or S-wave event prior to the wavefield inversion.

6. The method of claim 1 wherein the parameters of the source mechanism are represented by a moment tensor.

7. The method of claim 1 including the step of minimizing the difference between recorded signals and synthetic signals.

8. The method of claim 1 including the step of minimizing the difference between recorded signals and synthetic

signals, wherein said synthetic signals depend on source location, receiver location, time and source mechanism.

9. The method of claim 8 wherein the step of minimizing the difference between recorded signals and synthetic signals includes a grid search over source locations, origin times for an optimized source mechanism.

10. The method of claim 1 further comprising the step of determining location and origin time of a source represent the fracture.

11. The method of claim 10 further comprising the steps of
- estimating the initial origin time at possible source locations;
- carrying out a grid search around the estimated origin time for each source location;
- for said origin times finding the unique solution of a moment tensor of the source;
- evaluating the least-square misfit between the recorded signals and synthetic signals derived by calculating the signals caused by a source of said moment tensor at the receiver locations; and
- storing the best fitting solution for each source location.

12. The method of claim 1 wherein a source time function of the fracture is approximated by a delta function.

13. The method of claim 1 including the step of evaluating a Green's function to derive the source mechanism from the recordings.

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Application No: GB 0330097.7
Claims searched: 1-13

Examiner: Stephen Jennings
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Patents Act 1977 : Search Report under Section 17

Documents considered to be relevant:

Category	Relevant to claims	Identity of document and passage or figure of particular relevance	
X	1,6,10	US 5377104	(Sorrells et al) See column 3 lines 60-64, column 4 lines 51-61, column 4 line 64 - column 5 line 24, column 8 lines 15-17 and column 8 lines 45-55
X	1,6,10	US 4516206	(McEvilly) See column 5 lines 11-34, column 9 line 67 - column 10 line 2 and column 10 lines 39-44
X	1	US 5996726	(Sorrells et al) See abstract and column 6 line 46 - column 10 line 58

Categories:

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The following online and other databases have been used in the preparation of this search report :

WPI, EPODOC, JAPIO, INSPEC